BUREAU OF LAND MANAGEMENT

TRIBAL FORUM ON ONSHORE

ORDERS 3, 4 & 5

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Afternoon Session 1:00 p.m. - 4:00 p.m.

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501 Camino Del Rio
Held in Ballroom
Durango, Colorado 81301

I N D E X

P R O C E E D I N G S

THE FACILITATOR: Hi. I'm Liz O'Brian. I'm the facilitator today. I work for myself, so I'm not part of the Bureau of Land Management or the Department of Interior. And my job is just to make sure that this meeting flows so that you all don't doze off at 2:00 or 3:00, or whenever that caffeine thing hits.

Thank you so much for coming today. It's a beautiful day in Durango. We had a meeting this morning that was quite productive and informative, and we welcome you.

I'd like to introduce Lonny Bagley, who is the deputy state director for Colorado for the BLM.

MR. BAGLEY: Thank you, Liz. Well, welcome to this afternoon's session. I'll introduce our acting district manager, Matt Azhocar. And, again, welcome to this afternoon's presentation on Onshores 3, 4 and 5.

This is a regulatory rewrite of the Rules, and we'll have three subject matter experts here to talk about those Rules today.

And as Liz pointed out, I am Lonny Bagley. I'm the deputy state director for Energy, Lands, and Minerals for BLM here in Colorado. Today with me, we have Dylan Fuge, who is the senior advisor for our director back in DC. We have also Connie Clemmentson. Where is Connie? Connie is our field manager here. Sharon Borders is in the back. She is our public affairs officer here in the Southwest District. And who did I miss? Anyone from BLM? Sue Mehlhoff. Sue is the branch chief for fluid minerals in the State office in Lakewood.

And so again, welcome to this afternoon's session. We're here to talk about Onshores 3, 4, and 5 and regulatory packages that we'll present today. The comment period has been extended to December 14th as the cutoff date for comments, so this will be an informative process for those Rules.

We will take comments today, and we have a court reporter here taking those comments. And those comments will be used in the development of the Final Rule.

So today I was going to run these sessions is -- we're going to start off with Rich Estabrook. He's standing over here. He's going to introduce the package of Rules and what we're doing with the rule-making process.

And Mike McLaren, he's a petroleum engineer out of Wyoming who worked on No. 4, and Mike Wade, who is our expert for Onshore No. 3, site security.

So, again, welcome to the discussion, and now I'd like to introduce our assistant director, Mike Nedd, from DC to give a few opening remarks to the session. Again, welcome. And here you go, Mike.

MR. NEDD: Thank you, Lonny, and it's certainly good to see all of you -- a packed room, almost. We appreciate you coming out to visit with us and give some comments. We began this effort a few years ago when we initiated the updates in these key oil and gas operational Rules commonly referred to as Onshores 3, 4, and 5.

Today is just part of that comment period or that discussion that is going on, looking for your very valuable input. We believe to develop a very strong rule input from industry and others is critical, and so today is part of that.

As you know, the BLM manages 46,000 leases or 100,000 wells, and in FY14 produced over $27 billion in revenue. Of that, about 3.1 billion was in royalty collections. So this is a heavy lifting. It's very important that we get it right. So as we move forward to finalize this, we are looking forward to hear from you.

Part of the stress in this is dealing with the Government Accountability Office and the Office of Inspector General put out a few reports that said we needed to straighten our data gathering. We needed to have more consistent policy. So these Rules are going to help address that.

The Royalty Policy Committee is a committee for the Secretary of Interior who made some recommendations in 2007 that said we needed to look across the board of how we're managing oil and gas, onshore oil and gas. So updating these

Rules will help to address that.

As Lonny said, we will continue to take comments through December 14. We ask for those comments either today or you can mail it in or send it by e-mail. Towards the end of the PowerPoint, you will see some addresses for that, and certainly as Richard and Mike and Mike go through this, we want to hear from you. We want to hear those points that may not be clear.

We will attempt to answer those questions if we can. Certainly, we may not be able to answer all of them, but the idea is to get them on the books, get them out, and then get your comments in, what is true data, information or data.

Again, thank you for being here today. We're going to spend the next two, two and a half hours doing that. And at this point, I would like to turn it over to Richard and have him kick it away.

MR. ESTABROOK: Thank you, Mike. My name is Rich Estabrook. I'm a petroleum engineer. I work out of the Washington office, actually for Mike Nedd, although I live in the north coast of California, which is pretty nice.

So I'm going to run through a couple of overall general things, and after I do that, I will turn it over and start getting into the nuts and bolts of our proposed revisions.

I'll first turn it over to Mike Wade. He'll talk about site security, FMP, commingling, and then I'll turn it over to Mike McLaren. He'll talk about oil measurement, and I'll wrap it up with gas measurement.

This is our outline for the presentation part of it today. I'm going to talk about why these regulations are important. Why are we revising these regulations? And then as I said, I will cover changes common to all three proposed subparts. And that includes a new proposed part 3170 in the regulations.

Mike Wade will cover the revisions to Onshore 3. Mike McLaren, Onshore 4, oil measurement, and me, I'll cover Onshore 5, gas measurement.

And the plan for today -- I hope this work outs okay -- we're doing all the presentations up front and get them out of the way, and the rest of the time will be your time to respond to comments, however you want to do this. We'll try this and see if it works out okay. I hope it works out okay.

So why are these regulations important? I want to talk about royalty determinations. These regulations are obviously about money and royalties to the Federal Government and the Indian Tribes. And I thought it might be useful just to go through how royalty is actually calculated.

Royalty on oil equals the royalty rate on a Federal or Tribal lease, which is usually a fixed number, not always, times the volume of oil in barrels removed from that lease in a given month, times the dollar value of that oil in dollars per barrel.

The API gravity, the quality of the oil, is not a direct multiplier in royalty value, royalty determination, but it does affect the dollar value of the oil, so it is also an important component is the quality of that oil.

The royalty rate is set in lease terms. That's not what these Orders are about. That's a whole separate thing. We're not going to get into that here.

The dollar value of the oil is established by our Office of Natural Resources Revenue. That is not a BLM responsibility. It is a Department of Interior responsibility, but not our agency. They figure out how much that oil is worth and how much you have to pay royalty on.

Onshore Order 4 and to some extent Onshore Order 3 talk about the volume. The goals of Onshore Order 4 and Onshore Order 3 are to ensure that the volume, which goes right into the royalty calculation, is accurately measured and properly reported. That is what the provisions of Onshore Order 4 require, and that's -- the proposed revision to these Orders will directly affect the accuracy of that number.

Onshore Order 4 also dictates how the gravity or the oil quality is determined. That's also a function of Onshore Order 4. Again, that is not a direct multiplier to royalty, but it is certainly a factor.

For gas measurement, it's very similar. Royalty on gas is the royalty rate on the Federal or Tribal lease times the volume of gas removed from that lease in a given month, times the heating value of that gas, and then times the dollar value.

As with oil, the royalty rate is established in the lease terms and is not something that we're going to talk about -- these regulations do not address royalty rate.

Dollar value of the gas, again, is established by the Office of Natural Resources Revenue. That's a different agency, although within the Department of Interior. Onshore Order 5 and to some extent Onshore Order 3 directly deal with the volume -- the measurement and reporting of the volume removed or sold from a Federal or Tribal lease and, therefore, the provisions of Onshore Order 5, in particular, will affect the accuracy and reporting of that volume.

Onshore Order 5 also talks a little bit about heating value and the determination of heating value. One thing I'd like to point out kind of up front here is that in this equation or formula, you'll see that both volume and heating value have an equal influence on royalty pay.

So, for example, if the volume is reported 10 percent in error, the royalty will be 10 percent in error. If the heating value is reported 10 percent in error, the royalty will also be 10 percent in error. They have an equal bearing -- volume and heating value. One of the things I'll discuss in more detail, I want to get into Onshore 5, is the heating value aspect, and that's one of the things we really, really increased.

So why are we revising these regulations? Before I get into exactly the reasons, I want to tell you exactly what we are proposing.

What we are proposing is a brand-new regulatory subpart or part, Part 3170. That would be a brand-new part of the 43 CFR Regulations. Under that part, all things related to measurement and production would be included.

For example, any definitions common to any measurement-related activities would be included in this Part 3170. New requirements for recordkeeping would be included in this Part 3170. Requirements pertaining to bypass and tampering variances and appeals and enforcement will also be placed in this overall catch-all part of 3170.

Included in Part 3170 would be three subparts. The first subpart would be Subpart 3173, which would replace the existing Onshore Order 3, and it would include items such as site security, FMP, which is Facility Measurement Point, commingling, and off-lease measurement, and Mike Wade will be going into a lot of detail about that.

Subpart 3174 would replace Onshore Order 4, and it deals specifically with oil measurement. And Mike McLaren will be getting into the nuts and bolts of that.

Subpart 3175 would replace Onshore Order 5, and it would also replace statewide Notices To Lessees for electronic flow computers.

I'm sure some of you are aware that in the late 2000's, starting in 2014 in Wyoming and going through about 2009 or 2008, each State office jurisdiction passed or promulgated its own Notice to Lessees dealing with electronic flow computers.

So if you're from Colorado, for example -- how many here work in the Colorado area? Okay. How about New Mexico? Okay. So if you're in Colorado, there's a Notice to Lessee -- I believe it's 2007-1 -- that includes provisions for electronic flow computers on Federal Indian land.

If you're in New Mexico, I believe it's 2008-1. This proposed Subpart 3175 would replace those.

And Subpart 3175 deals explicitly with gas measurement, and I'll be getting into the nuts and bolts of that.

So why revise these Orders? Well, first of all, they were last revised -- actually they were promulgated for the first time in 1989. All three Onshore Orders, 3, 4, and 5, are 26 years old, which isn't necessarily bad, but it leads to a number of things.

For example, current Orders do not address new technology or incorporate the latest industry standards and practices. For example, Onshore Order 4 has no mention whatsoever of Coriolis meters for oil measurement.

Back in 1989, Coriolis meters, I'm pretty sure, were around, but they were not used very commonly, at least, so there's no mention of Coriolis meters in Order 4. We're proposing to include Coriolis meters.

There are gaps in the existing Orders that need to be addressed. For example, in Onshore Order 5, there's one and only one requirement relating to the determination of heating value. And that is, the heating value has to be determined at least once per year, and that's it.

Now, as I showed in that little equation, volume and heating value carry the same rate when it comes to royalty. There's 25 provisions in Order 5 for volume, and one and only one in Order 5 for heating value. So that's a gap that needs to be fulfilled, and that's what we're proposing to do in these regulations.

As Mike Nedd mentioned, there's also a number of Government agencies that we have to report to or that oversee us, and one of them is the GAO or Government Accountability Office. They audit us from time to time to make sure we're doing our job, and in 2010, they came out with a report and numerous recommendations dealing with our lack of current regulations.

The OIG or Office of the Inspector General is another agency that makes sure we're doing our job, and they have done numerous audits, always saying we need better regulations.

And RPC, which Mike mentioned, is the Royalty Policy Committee. They did an exhaustive study in 2007 and came up with 110 recommendations of things the Department needed to do -- 110 regulations the Department needed to do, and of those 110 recommendations, 12 dealt directly with measurement issues and the need for new regulations.

Basically, we need to revise these Orders to improve measurement, accuracy, reporting, and accountability, and that's the bottom line. And that means improving royalty accuracy, reporting, and accountability, as well.

So I'm going to cover now some general proposed regulations that would overlap or pertain to all three Onshore Orders -- all three revisions that we're proposing here.

The first one is -- how many people in here have read our Onshore Orders?

(Show of hands.)

MR. ESTABROOK: Okay. Good. And, as you know, in our Onshore Orders, there's always -- the routine is always the same. There's a requirement, and then there's a violation severity if you don't comply with that requirement and major or minor, and then there's a corrective action and time frame. So each one of the specific requirements in the Onshore Orders has major, minor, and corrective action, and time frame.

Well, this has been widely misinterpreted by both BLM and industry as being absolutely concrete. So if this violation says it's a major violation, then people have interpreted it to mean, well, it's always a major violation, period.

And that was never the intent of these enforcement actions in the Onshore Orders. The intent of these enforcement actions was simply to be some guidance to our inspectors on how to look at things. We never intended them to be cut-and-dried, set in stone.

So in our proposed regulations, what we're proposing to do is remove the enforcement actions from the Onshore Orders and put them in a manual or handbook that our inspectors would carry.

This manual or handbook could go into great detail about extenuating circumstances. For example, a major violation on a high producing well where there's a lot of royalty risk, a lot of royalty at stake, but the same violation on a little marginal well that's just barely hanging in there, maybe it's not that big a deal and should be a minor violation.

And those kinds of nuances we need to address, and we're proposing to do that in an enforcement handbook, rather than in a regulation.

The Onshore Orders currently have one and only one immediate assessment, and that has to do with Federal seals. The proposed regulations would increase the number of immediate assessments. They would all be a thousand dollars.

The purpose of the immediate assessment is not to be punitive. It's to basically reimburse the BLM for liquidated damages due to noncompliance with the provisions for which we're doing immediate assessment.

I don't understand liquidated damages. If there's attorneys in the room -- I think there is -- they can do a much better job of explaining that than I can.

In the current Onshore Orders, any technical review of a variance request for another type of meter or another procedure, all technical reviews are left up to individual field offices, and I don't know how many of you have dealt with this issue.

I know I hear complaints from industry because we're not exactly consistent from field office to field office on how we look at and approve things.

For example, I know there's a case in Wyoming that was dealing with an alternate type of gas meters where one office basically said, "Yeah, this meter is fine."

Another office in the same state said, "Yeah, it's okay. You can use it, but here's a list of conditions you need to use it under," and the third office said, "There's no way you're using this device."

So what we're proposing is that we would establish what we're going to call a production measurement team, a central team of measurement experts for BLM. They would look at and review all requests for new meters, new technology, new procedures.

We believe this would improve consistency because if we approve this meter, it's approved nationwide. You don't need a variance request from a field office anymore. It's approved nationwide. This would, also, we believe, dramatically increase the longevity of these regulations.

Right now, we're dealing with things like Onshore Order 5, which doesn't even talk about electronic gas meters. And this is going to be the case. You know, these regulations, if they're finalized, they could be in place for another 25 years.

Who knows what technology is going to be out there in another 25 years from now? But with this production measurement team concept, we have the flexibility to approve new devices, new technology as they become available and are accepted by the industry. We believe this would increase the longevity of these regulations because we won't be tied to just the cookbook regulations as they were proposed.

How this would work or how we're envisioning it is that for things like different types of differential meters for gas or Coriolis meters or whatever the new technology or procedure is, the operator or a manufacturer or somebody could submit this new device or new procedure to the production measurement team. The production measurement team would review it once to see if it meets our needs, and then if it does meet our needs, it would be placed on a national website that this device or this procedure is approved, and there might be some conditions with it -- it's approved under or with these operating conditions.

And then once that is done, any operator, if they want to put in and install a new device, they just have to go to the pick list on the BLM website and see what is approved, and they could use whatever is approved.

If they want to add something new, you submit the test results to the production measurement team, and if we feel it's appropriate, that will be added to the list. So we're hoping that this not only improves consistency from office to office, but really gives us the flexibility to review and approve new technology as it becomes available.

Onshore Orders 4 and 5, anyway, are very cookbook. I'm sure you're aware of that if you're familiar with Orders 4 and 5. They're very, very prescriptive of what you have to do.

There's no performance goals in either Onshore Order 4 or 5. What is the objective of these things, anyway? What are we trying to achieve? It's just a list of things you have to do.

What we're proposing is that Onshore Orders 4 and 5 would contain explicit performance goals for uncertainty and bias and verifiability.

So the Onshore Orders, the new replacement Onshore Orders 4 and 5, would have both explicit performance goals and a cookbook approach. So if you want to know what you have to do, you just follow the cookbook. If you want to do something different, then you just have to meet the explicitly stated performance goals.

If you can prove that your new procedure or new device can meet these explicit performance goals, that will get approved. It provides tremendous flexibility, we think, for industry and for us.

The goals -- when we established performance goals, which Mike and I will both go into, the goal was to try to get accurate measurement for the higher volume meters and give economic relief, lower performance goals, for lower volume meters.

We're trying to achieve some kind of balance between accurate measurement and being reasonable from an economic standpoint because we know some of these things are expensive.

Specifically, now, Part 3170, this is the overall overarching part that covers both 3173, 3174, and 3175. Currently in the Onshore Orders, our requirements apply only to operators.

So here's the scenario that is not that uncommon. Oftentimes, the meters on which you pay royalty are not owned by the operators. They're owned by a purchaser or transporter, but we have no authority over the purchaser or transporter, so we request audit information from this meter, from you, the operators. And you, the operator, goes to the pipeline company and says, "BLM is doing an audit, and they need this information."

And the pipeline company may say, "Well, that's too bad. We're not going to provide it to you" for whatever reason. The BLM now has to take an enforcement action, and we take the enforcement action against the operator, even though the operator has tried to comply.

What we're proposing is that requirements for recordkeeping would apply to purchasers and transporters through the royalty settlement point or point of first sale collection, whichever comes first.

So now, if the purchaser or transporter owns that meter, we could go directly to that purchaser or transporter to supply that information, and if they refuse to give it to us, we can take enforcement action directly against the purchaser or transporter.

This authority to do this is actually a latent authority that has been around for a long time in the Federal Oil and Gas Royalty Measurement Act. This is an authority granted to the Department that we have never exercised before, but we're proposing to do it now.

Definitions, I kind of covered this. Right now, each Onshore has its own definition. A lot of them overlap. We're going to take definitions common to all three Orders and pull them out and put them in one place and in the overall Part 3170.

Right now, each Onshore Order has a variance, some variance language. It's pretty consistent, but there's a little bit of difference. We're going to pull that variance language out and put it in 3170. We're also going to give additional guidance on how to request and review processes for these variance requests.

And with that, I'll turn it over to Mike Wade to talk about Subpart 3175.

MR. WADE: Thank you, Rich. Like Rich, I work for the Washington office and report to Mike Nedd's staff. And I primarily have been dealing with the 3173 site security side of it, and we're going to look at some of those.

Currently under Order 3, there's no guidance or requirements for commingling or off-lease measurement. Totally moot in Order 3. We are proposing to add some very specific procedures and requirements to be applied for applying for commingling and for applying for off-lease measurement approvals.

The BLM's proposing to currently approve only if there are no royalty impacts from the allocation. So that is the first one -- or if we can determine that it's low volume property and we can commingle based on allocation because low volume is less economically viable, we can approve those instances, as well.

And then there would be BLM [sic] to determine for extenuating circumstances, and those would be applied for by the operators -- basically very similar to what we have currently in some other policies that we have recently implemented.

We would review the existing commingling approvals when the operator applies for a facility measurement point. This would be to ensure that the old or commingling approvals are in compliance with the new proposed regulations.

Order 3 applies to sales and allocation meters regardless of what is associated there, and the measurement relating to royalty payment is not even considered as part of it. We want to change that where it would apply to measurement affecting royalty and not necessarily the whole world. BLM approved a tracking of a facility measurement. That was one of the recommendations that came out from numerous OIGs, GAOs, and other agencies have put that burden on us to determine at least some way of setting that.

Right now, what we have -- we believe from a BLM inspector's perspective as a point of royalty measurement may not be what the operator is actually using for a royalty determination point, and that has created many problems.

Oil sales run tickets right now are covered under Order 3. That is going to be moved into -- for the tickets into Order 4 or actually 3174, and we are adding some additional documentation requirement for such things as water draining, hot oiling, et cetera.

Primarily, right now, we record seal number on, seal number off, date, and a basic reason for, for example, water drain. We're wanting to include, or proposing to include a few extra pieces of information, like how much fluid was in the tank when you started the draining operation, how much was in the tank when you finished.

Same way with the hot oiling and other things like that. It's an improvement in the quality of the data that everybody is required to keep.

End-of-month inventories are not currently required in Order 3. We are proposing that operators maintain records of end-of-month inventory.

No information requirements for royalty-free. Some people call it beneficial use, used on lease -- same term.

We're proposing in 73 to add some information in your site security diagrams if you're going for claiming of beneficial use of the make and model and some Btu ratings for equipment that is going to be used on lease -- and/or to, if you're going to measure it, then measure it and give us some information and tell us how your royalty-free will be determined -- estimated or measured.

Right now, there's requirements for a self-inspection program and site security plan that the operators are required to maintain. We are removing those completely. With the additional information on such things as fluid drains, better information on your seal records, why it was added and removed, we feel those items would no longer be appropriate, additional and more work for you to do.

We are asking for some very specific comments on Order 3 from the field from everyone right now -- comments on whether or not this 10 percent rate of return is appropriate for determining whether off-lease measurement, commingling for low volume. Is it a good number? Is it a bad number? We pulled that number, made our best guess.

Also, we're asking for comments on the time frames and the volume thresholds for submitting your applications for

FMP. The proposed rule basically breaks it down into thirds -- high volume production being the most critical, which would be the first -- I believe nine months, and then followed by the middle level of production for a second level of nine months, and then the last lower volume wells, the last nine months to apply for.

Of course, none of your measurement would be curtailed if you applied for FMP and we have not approved it. Your measurement would continue on until such time as we have approved or given you your FMP number.

So if it took us 36 months to apply -- to approve a high volume one, there would be no impact on your requirements to submit or shut down any leases or any production.

With that, I'm going to turn this over to Mike McLaren and let him do the oil measurement.

MR. McLAREN: Hello. I'm Mike McLaren. I'm a petroleum engineer in the Pinedale field office in Wyoming. I'll talk briefly here about what we're proposing for the oil regulation.

So currently the Order 4, as Rich discussed, has no overall performance standards cookbook. We are proposing some performance standards for uncertainty, and what we are proposing is basically three tiers.

If you're greater than 10,000 barrels a month, we're looking for uncertainty at plus or minus .35 percent.

If you're between 100 barrels per month and less than 10,000, we're looking for uncertainty, we're proposing, of plus or minus 1 percent, and if you're less than 100 barrels a month, we're proposing plus or minus .25 percent.

And where we got these numbers, basically the plus or minus 3.5 percent, was the uncertainty calculation for the Current Onshore 4 report for LACT system using a positive displacement meter.

The 1 percent is based off tank gauging under the currently Onshore Order 4, and that 1 percent is withdrawing 250 to 300 barrels out of a 400-barrel tank, and the 2-1/2 percent is -- was basically -- I believe it was 40 barrels out of a 400-barrel tank.

The third tier is essentially for the very low volume producers, the low uncertainty. They're not going to be spending a lot of money on measurement.

The current Order 4 references industry standards that were published in 1989. We're proposing to incorporate the most current API standards, 21 of them, and two ASTM standards.

The current Order 4 states requirement for pressure vacuum thief hatch or line valve. What we're proposing is a pressure vacuum relief value set at inlet/outlet pressure greater than thief hatch settings and we also in the proposal are proposing to maintain pressure backing integrity on the tank, not just the equipment installed.

The current Order 4 includes requirements for gauging and sampling. They're random. There are no requirements in the way they're listed in there.

What we're proposing is to specify the sequence of the gauging activity and the requirements for each one of those sequences. That's based on EPI standards and sequences following the EPI 18.1 standard.

The current Order 4 requires two consecutive gauges within 1/4 inch. We're proposing two identical gauges or three gauges within 1/8 inch, and that is based on the newest API 3.1 standard.

Order 4 currently requires tank calibrations. However, there are no increments required for the calibration table. We are proposing calibration tables be in 1/8-inch increments to match the current standard.

The current Order 4, it's two methods to measure -- either a lease automatic (inaudible) system requiring the automatic temperature compensator or temperature gravity compensator using a positive displacement meter.

What we're proposing is to prohibit the automatic temperature gravity compensator, and require a temperature averager, and we are proposing to allow a Coriolis meter in place of the positive displacement meter.

The current Order 4 is two methods for measuring oil tank gauge. We are continuing with the tank gauge and LACT systems and proposing the use of the Coriolis measurement system.

So we're proposing some requirements for the Coriolis measurement system -- basically minimum 8400 pulses per barrel as specific specifications. We have specific specifications for the Coriolis meter including reference accuracy, influence effects, stability, pressure drop.

We're proposing to notify BLM within 24 hours of changing any of the calibration factors. We'll require nonresettable totalizers. We're going to -- for the proving, we want verification that the meter is zero prior to proving.

We want the Coriolis meter to determine net standard volume. And we have a proposal in there for API gravity to be determined either from composite sampling or from the average density reading of the Coriolis meter itself.

We are proposing some onsite display requirements and requirements for the quantity transaction record and configuration log and event log and alarm log.

The current Order 4 LACT proving requirements are if you're greater or equal to 100,000 barrels, it's monthly or quarterly. What we're proposing for the LACT and the Coriolis measurement systems is every 50,000 barrels or quarterly, whichever comes first, and we got that 50,000 barrel number from doing a statistical analysis of meter factor change -- at what volume does cost to prove the meter equal to the risk to the royalty overpayment or underpayment. We used average proving cost of $550, and we came to 50,000 barrels was the number that the risk to royalty was that $550.

The current Order 4 has no standards for prover sizing, no standards for proving conditions, and no standards for the minimum pulses during the proving run.

What we're proposing would be minimum-maximum fluid velocity for the prover sizing. We are requiring proving at a normal flow rate pressure and gravity, and we define -- we have a proposal in the Rule for what that normally would be. And proving run generating less than 10,000 pulses, we're requiring pulse interpolation.

Currently measurement tickets are not a requirement for LACT systems. We're proposing in 3174 to measure -- no, to generate a measurement ticket after proving and at the end of each month.

In there, we're looking for comments and field test data for the proposed uncertainty levels, the use of the automatic tank gauging systems. We're hoping to get some field data in from you guys on these systems to evaluate for possible incorporation into the final Rule.

We're looking -- we got some proposals for a composite sampling system on the Coriolis. What we have is the option, if you don't want to install a composite sampling system, then our proposal states that you wouldn't deduct sediment and water from the volume because we have no way to determine it.

So it's kind of up to the operator to evaluate the cost to you to buy a composite sampling system and deduct the sediment water or not deduct the sediment water and pay the difference in whatever the royalty.

We're asking for ways to determine a meter factor if we have variable flow rates, pressures, or oil gravities. We're asking, do we want to average meter factor for that or incorporate a dynamic meter factor that will automatically adjust for the flowing conditions that change?

So that's the overview of what we're proposing for the oil measurement, and I'll give it to Rich.

MR. ESTABROOK: I'm going to talk about proposed changes to the gas measurement 3175, and after I'm done, we'll open it up for questions and comments.

So currently Onshore No. 5 only addresses orifice plates and mechanical recorders. Again, Onshore Order 5 was promulgated, as were all the other ones, in 1989. They weren't a big thing back then, so they were not addressed.

The EGM systems, electronic gas measurement systems, we addressed those through the State-wide Notices to Lessees that I talked about earlier.

Proposed 3175 would maintain orifice plates as the main measurement for a way to measure gas. We like orifice plates. We think that the accuracy is reasonable, and they also provide a high degree of verifiability, which is one of our most important missions.

Proposed 3175 would still allow mechanical recorders, chart recorders, under some circumstances that I will get into. It would allow approved electronic gas measurement systems, and it would have specific guidance for alternate measurement, different types of meters, and isolating flow conditions.

As we discussed earlier, none of the Orders have any performance standards, although the existing 5 does have three tiers of requirements. It's in my next slide, which I'll show you.

What we're proposing in 3175 is to establish four tiers of performance standards based on average flow rate. So this is the existing Onshore Order 5. And the average monthly flow rate is shown on the Y axis here.

So currently, if your meter is measuring more than 200 mcf per day, all the 26 or however many requirements there are in 5 would apply to that meter.

If you're flowing less than 200 mcf per day, you're no longer required to have continuous temperature recording under Current Onshore Order 5. If you drop below 100 mcf per day average monthly flow, now you don't need a continuous temperature recorder, and you no longer have to run the DP, the differential pen, and you are also exempt from our beta ratio limits which is .15 to 17 [sic]. That's the current order.

In the proposed order, we kind of like this idea of having a tiered requirement, so we sort of expanded on this a little bit. We're going to have four tiers or we're proposing four tiers. And we have a name for each tier.

If your meter is measuring more than 1,000 mcf per day on a monthly basis, we would call that a very high volume FMP. If you are measuring between 100 and 1,000 mcf per day, we would call that a high volume FMP. If you were measuring between 15 and 100 mcf per day, we would call that a low volume FMP, and if you're measuring less than 15 mcf per day, we would call that a marginal FMP, and the performance standards and the cookbook criterias proposed in 3175 would key off of these -- or one of these four categories.

So our performance standards for gas include uncertainty levels for both volume and heating value, bias, statistically significant bias in the measurement, and this all-important, less-easy-to-define thing called verifiability.

Verifiability is one of the key factors in any measurement that BLM oversees. Verifiability is the ability for the BLM to independently inspect and verify every single aspect of that measurement all the way from the equipment doing that measurement all the way through to the final volume and heating value.

So for very high volume FMPs, over 1,000 mcf per day, our performance standards would be 2 percent per volume and 1 percent for average annual heating value. It's a little bit of a different concept.

We would not allow any statistically significant bias, and every aspect of the measurement would have to be independently verifiable by us.

For high volume FMPs, the uncertainty would be 3 percent, plus or minus 3 percent, for volume. The average annual heating value uncertainty would be plus or minus 2 percent. Again, we would not allow any statistically significant bias, and all measurement aspects would have to be verifiable.

For low volume FMPs, less than 100 mcf, between 15 and 100, you would be exempt from uncertainty requirements. We would not allow any statistically significant bias, and we would still require independently verifiable measurement.

For marginal volume FMPs, the only thing that we would require is that we have some level of verifiability.

Onshore Order 5 currently adopts one and only one industry standard, and that's AGA Report No. 3, 1985, which talks about orifice plates and mechanical recorders and flow rate calculations.

Proposed 3175 would adopt the newest API and GPA standards covering the primary device, orifice plates, electronic gas measurement systems, flow rate, volume and heating value calculations, and gas sampling and analysis.

Now, why is this important? I'll give you one example. The current 1985 standard has requirements for the placement of straightening veins if you're using straightening veins upstream. Based on test data, that was done a long time ago.

In the early '90s, a bunch of new test data was generated, and they discovered that if you put straightening veins where the 1985 AGA Report No. 3 tells you to, in many instances, you bias your measurement by 1 or 2 percent.

So currently, we enforce a standard that results in measurement bias that we know about in certain circumstances. So we want to adopt the new standards that will result in better measurement.

The current Onshore Order 5 has no requirements for inspection of meter tubes. API 14.3.2 goes into great detail about the requirements for meter tubes -- the roundness, surface roughness, other things.

And we feel that if API is concerned about the construction and condition of meters tubes, that maybe we should inspect them once in a while because they can affect measurement. If they didn't affect measurement, I don't think

API would have standards for them.

So what we are proposing in 3175 is periodic inspection of meter tubes per this frequency. For marginal volume FMPs, you would never have to inspect the meter tube.

For low volume FMPs, you would have to do a visual inspection once every five years. A visual is something like a baroscope, where you go in through a pressure tap. You don't have to disassemble anything. You have to shut it down and just go do a visual inspection and look for scale buildup or plugging, excessive pitting, or some other condition.

High volume FMPs, we are proposing a visual inspection once every two years and a detailed inspection once every ten years.

A detailed inspection would include or would require complete disassembly of that meter tube and going in with a measurement device to check the roundness. For very high volume FMPs, we'd require a visual inspection once per year or a detailed -- and a detailed inspection once every five years.

Order 5, mechanical chart recorders are automatically approved. That's all that is approved. 3175, mechanical recorders would be restricted only to those meters measuring less than 100 mcf per day. We believe that the uncertainty characteristics of chart recorders are not well enough defined to meet our uncertainty, our proposed ununcertainty requirements for high and very high FMPs.

Order 5 has one and only one requirement relating to heating value, and that is that it be determined at least once per year. There are no requirements in Order 5 about where do you take the sample? How do you take the sample? How do you analyze the sample? How do you report?

And again, I'll reemphasize the fact that heating value and volume play equally on royalty. Proposed 3175 would establish a new sampling frequency.

For marginal volume FMPs, we'd just stay with the once per year. For low volume FMPs, it would be a fixed once every six months frequency, and for high and very high FMPs, we are proposing something a little different. We are proposing something a little bit different.

We would establish an initial sampling frequency, and once we have enough samples to do a statistical analysis, we could then adjust your frequency upward or downward to maintain or to obtain that heating value uncertainty that I talked about earlier.

So for high value FMPs, the sampling would be three months. After we have enough samples collected, enough heating values collected, we could determine the variability of the heating value from sample to sample.

If it's a very high variability, we could then, using statistical analysis, increase the required sampling frequency to something more than once every three months in order to achieve our set 2 percent uncertainty level.

For very high volume FMPs, the same idea is what we are proposing. You have an initial sampling frequency of once ever month. On the variability of that heating value from sample to sample, we could either increase sampling frequency or decrease it.

So, for example, if you took a year's worth of samples and the heating value was just dead on every time, we could say, you can now sample once every six months and still achieve our 1 percent uncertainty level. On the other hand, if your heating value is all over the place, we could require something more frequent.

Continuing with this, if you could not achieve the uncertainty level -- and this is just for high and very high FMPs. If you could not achieve that uncertainty level through spot sampling, we would require you to install a composite sampling system or an online gas chromatograph.

Also, we are proposing to develop a new database. It's called the Gas Analysis Reporting and Verification System or GARVS. The proposed 3175 would require all gas analyses used for royalty determination to be entered into the GARVS. It could be key entered or it could be imported from a gas analysis reporting and verification system.

UNIDENTIFIED SPEAKER: Could you tell us what GARVS is again?

MR. ESTABROOK: Gas Analysis and Reporting Verification System. This GARVS software would have the statistical analysis built in it of determining the sampling frequency required to achieve our set level to uncertainty.

Order 5 has no requirements for sampling location or method. It has no requirements for gas chromatographs. Proposed 3175 would require the sampling probe to be placed one to two times dimension DL downstream of the primary device.

Now, this is one of these proposals we're kind of throwing out to you guys. So we want comments because we know it's a little off the wall, and I can explain why maybe later.

And this is one of the things we specifically want comments on and data on if there is any data out there. We believe this is necessary because the GPA and API requirements for sample probe locations are all based on fluid at -- or gas at or above the hydrocarbons dew point.

Single phase -- and I think we know at least for lease-level measurement, that is just not reality. We are sometimes below hydrocarbon dew point, and we do get hydrocarbon liquids.

We're throwing out this idea that, perhaps, a sampling probe be placed closer to the orifice plate because it's the primary device, because it's high velocity and high turbulence, might take some of those entrained liquids and vaporize them and get them into that probe so we can account for them.

Otherwise, we believe there's unaccounted for gas or unaccounted Btu's in the form of liquid hydrocarbons that are going through the meter that are not being accounted for.

We are proposing four spot sampling methods that we would allow. Our proposal is we would establish requirements for gas chromatograph, calibration, and operation. And the last one is another one we're looking for data on.

Our proposal is if you get a normal gas analysis, you got a hexane plus greater than .25 mole percent, we would like to see a second analysis, an extended analysis.

Order 5 has no requirements for Btu reporting. Btu's can be reported on a number of different bases. They can be reported as gross or net. They can be reported as real or ideal or dry. They can be reported as dry, wet, or as-delivered. They can be reported at a number of different pressure bases and generally at some 60 degrees for a temperature base.

So for a single sample, a single gas sample, you multiply all those together. There's like 30 or 40 Btu values you can get from a single sample. We are proposing to define the conditions under which you report -- gross, real, dry, 14.73 psi, 60 degrees Fahrenheit.

Order 5 in the State-wide Notices to Lessees for electronic flow computers -- there are no requirements for independent testing of transducers or flow computers. In fact, all transducers and flow computers are accepted.

Now, under the State-wide Notices to Lessees, we already have an uncertainty requirement, 3 percent. The BLM has a tool that we use for enforcement of that requirement called the uncertainty calculator.

Transducers are a huge contributor for uncertainty, so that uncertainty calculator uses manufacturer data and published specifications for the transducers in the determination of uncertainty.

But as it stands now, there are no -- there's no transparency to those manufacturers' specifications. Those testing methods are usually proprietary, so we have no idea what those numbers even mean, if they're valid, if they're worse, if they're better.

What we're proposing is that all transducers used on high and very high volumes FMPs, including existing ones, would have to go through a standard public transparent testing protocol. The production measurement team would review the results from that testing and would develop a list of approved devices. And the uncertainties determined from that testing protocol would be used in the calculation of overall measurement, uncertainty, not the manufacturers' specs. We believe that's a more realistic analysis.

Finally some specific data and comment requests. Again, when you see specific comment requests in the preamble, it probably means that BLM is kind of putting something out there that we're really not super comfortable with, and we're seriously looking for some data and feedback.

And so these are the things for Order 5, 3175. Cost data to industry for testing these transducers -- now, be aware that the proposal is that if any one operator or manufacturer sends their equipment through the testing protocol, no one else has to do it. It's a one-time shot.

Let's say, Conoco takes this Rosemont 1151 and sends it to the testing protocol, sends it to the PMT. The PMT reviews it and puts it on the website. That's available for everybody. So it's a one-time shot, but we're curious to know what this is going to cost.

Also, in the proposed rule, the testing protocol would require testing on five transducers randomly selected from the assembly line. And our question to you guys is, is that a sufficient or excessive number of transducers in order for us to determine from a statistical standpoint whether or not the results from that testing is of value?

When we were writing the proposed Rule, there wasn't much out there really on gas chromatographs. GPA has some stuff, but not a lot. So we're looking to you to tell us if there are other standards that we have missed when it comes to gas chromatographs. Since we drafted these regulations, for example, API 22.6 has been published, which is a testing protocol for chromatographs. Is that appropriate for us to include in this Rule? I don't know.

Data showing water vapor saturation -- this gets back to that dry, wet, or as-delivered issue. And we can have a discussion on that. I'm guessing we will.

We are proposing that Btu's be reported dry. The wet or saturated basis for Btu reporting has no scientific basis whatsoever, and I'm sure most of you know that.

The as-delivered does have a scientific basis, but it's still an assumption. So dry Btu is kind of one extreme of what is physically possible. And as-delivered Btu is kind of another extreme of what is physically possible. The truth probably lies somewhere between those two.

We are going to be requesting dry, and we're hoping that industry has data to show that their assumption on as-delivered as saturated at meter conditions is actually legitimate. It's just an assumption. We have actually been asking this at AGI meetings for years now, and one company I know for sure has got that data, but we would like more.

This is the last bullet -- or not the last, but the next bullet showing correlations between sample probes and placement and composition. This is that one that we're throwing out there, the one to two times dimension DL for the sample probe placement.

Do you know of any data, can you supply us data that shows some correlation between sample probe placement and gas composition?

Now, this requirement came during a discussion, I believe in an API meeting, where someone said, "I have never seen any data." They were doing some testing on a different orifice plate. It was another type of device, and they would take a sample well downstream of the primary device and get one Btu value, and then they would take another sample closer to the primary device and get a much higher Btu sample. We're looking for that data if there is any.

Cost of retrofitting orifice meters to meet the eccentricity requirements of API 14.3.2 -- that was in the preamble as a request. We didn't have a good idea of what that would cost.

Another thing is that for chart integration companies -- again, this would be for meters flowing less than 100 mcf per day -- we would require mechanical recorder calculations, volume and flow calculations, to be done in the new 1992 or even the 2013 standard.

We know chart integration companies have been around for a long time, and probably many of them are still using the 1985 calculation. We would love to hear from chart integration companies to know what economic impact that would cause if we required them to update.

And, finally, data showing the difference between hexane plus and the extended analysis as an analysis of hexane plus and mole percent. We're saying is that if you get a hexane plus of more than a quarter of a mole percent, we want an extended analysis.

If you have data to show at even at 1 percent, there's no significant difference between a hexane plus and an extended analysis, we would like to see that data.

And I think that is it. Some additional comments -- there's a website up there. Boy, that's tiny print. Regulations.gov is the best place to go, I think, for comments.

There's also -- I'll just leave this up on the screen.

THE FACILITATOR: We'd like to take, like, a ten-minute break right now and then start with questions and answers and comments and whatever you have coming back. Thank you.

(A recess was taken from 2:11 p.m. to 2:23 p.m.)

MS. JENNIFER BRADFUTE: I just wanted to make a really brief comment about the FMP numbers, and that seems to overlap in all three of the proposed Rules.

Right now, it looks like it is contemplated that there would be a 11-digit code that would be used for an FMP number for each well. Many accounting and software systems that operators are using are not set up to accommodate an 11-digit figure, and so that's a really practical problem that I think a lot of members in industry are facing.

Also, currently, records are being kept in a form that's either lease-based or they have their own recordkeeping process, and that usually gets transferred over to different transporters, depending on the transporter. If you're working with a pipeline, it might be different from a trucking company.

And so I think what industry would like to see is a more practical solution where they don't have to overvamp [sic] their software packages that they are using.

MR. WADE: Yes. We can understand that particular issue, potential issues and problems. And we would appreciate any ideas you may have as a solution. We do have to realize that there are several hundred operators and two or 300 transporters and purchasers out there.

Each of them have their own unique numbering systems, recordkeeping systems, et cetera. I don't think we have the ability at this time to probably deal with multiple hundreds of different recordkeeping and numbering systems for everything that is out there. That would be possibly more confusing for everybody, including the operators and purchasers and transporters as you change property ownerships around, and all of a sudden, Company A is now operating what Company B had, and they're using Company A's new or old existing system. Company B had a different system, and nothing matches up.

So if you have got some suggestions on how we can deal with the numbering system, please submit them to us so we can try to see what we can work with.

MS. JENNIFER BRADFUTE: Okay. And are there any limitations to BLM's current computer system -- or is there any particular reason on why an 11-digit code was selected?

MR. WADE: In part, it was due to consultations with ONRR. They wanted to have something that if they were going to report it on their OGARS, it was compatible with their existing numbering systems.

So we needed to try to be compatible. We have to change -- it's changed data on a variety of different pieces of information between their OGAR system and our automatic fluid minerals support system, and there are pieces of information that we have to have from them and they have to have from us.

So because we have to transport information back and forth between each other, we need a way to identify what that information is, what it is related to as far as the well and case numbers, operators. So we need things to talk to each other back and forth electronically to be compatible.

MS. JENNIFER BRADFUTE: Is this something that BLM and ONRR would be willing to look at with people who have software backgrounds within the industry and have some further discussions about what current capabilities could already handle, instead of companies looking at purchasing new software packages, which could be an extreme burden for people to implement?

MR. WADE: Yeah. Could you submit that in your comments, please, so that we can take it to upper level management for those type of situations?

MS. JENNIFER BRADFUTE: Absolutely.

MR. NEDD: Hi again. This is Mike. Let me expand on that. If there are some companies out there, if you could include that in your comments, that would be helpful. So, again, as much data as you can provide to us would be helpful.

MS. JENNIFER BRADFUTE: Okay. Thank you.

MS. HEATHER RILEY: Thank you. I'm Heather Riley, regulatory manager for the San Juan Basin, WPX Energy. We're not prepared today to give specific comments as to the proposed regulations, but I would just like to say to you that you all have been looking at them for two years trying to put these together, and we're just kind of now seeing them so we have been trying to get an assessment of how these will affect us and certainly how they will all affect our economics.

We would like to have additional time so that we can really run that to ground and, in particular, where I'm operating out of the San Juan Basin, there is -- it's a complex area.

We have multiple leases, multiple owners. We have State fee, Federal minerals, as well as Indian allotted minerals. And we have been working within the current Rules trying to set up and establish our operations out there. And it's been very, very complex. We would like to have some additional time to look at the proposed Rules to see what it's going to do to us in the industry.

MR. NEDD: Again, thank you for your comment, and as we suspect, some companies will be asking for additional time. And, you know, we have extended it to December 14th. And so as we stand today, that is the time, and I would strongly suggest that to the degree we can get comments in by the 14th, please do that.

If it was to be extended beyond December 14th, I would then do some sort of notification, but as we stand today, that is where we are at, December 14th. And I know we have had different times, so I just wanted to be clear. We have December 14th as of today.

And we certainly would ask for comments to the extent you can. Please try to meet that date. And again, part of today's discussion was to clarify the discussion so our subject matter experts can render clarification on comments, but I appreciate the comments. Thank you.

MS. HEATHER RILEY: So one other question, quick question, would be about the assessments. You said that you're taking the language out of the proposed Rule for assessments, but you're putting it into a handbook. Will there be something that we will be able to see so that we know what the severity of the assessments will be?

MR. WADE: That will be for our proposal. What we are proposing in the handbook or manuals would be a system of whether it's a major violation or a minor violation and some descriptions on how to select time frames for correcting them.

As Rick pointed out, not all violations of -- a seal violation would be a perfect example. On a 200-barrel tank and only 2 foot of oil in the tank, should that be rated as a major violation?

Right now, interpretation of the current Order says yes, it is a major violation. And you have 24 hours, I believe is what it is you have to correct the problem. We would like to see that changed so that we have something a little more variable or adjustable so that we can look at specific situations. This one is not a major violation, and we can go with something other than 24 hours.

MS. HEATHER RILEY: On the immediate assessments, will there be an appeal process?

MR. WADE: As with all of our processes, including issuance of any type of noncompliance, the same appeal processes will apply there through the State Director's Review as outlined in the Rules and Regulations. We're still proposing not to make any changes to the appeals processes.

MS. HEATHER RILEY: Thank you.

MR. ESTABROOK: Just to follow up, I think you also asked if that enforcement handbook would be available to the public. It would be a publicly available document.

MS. HEATHER RILEY: Thank you.

MS. AMY ROTH: I am Amy Roth from E&B Natural Resources, and I'm from California today. Thank you very much for scheduling these hearings. We're glad to have an opportunity to speak.

E&B Natural Resources is a small company producing oil and gas. We employ about 270 employees, providing jobs and economic stability for our employees and their families. We provide a steady revenue stream to the BLM and the royalties that the BLM receives is shared with the State.

We would like to offer the following comments regarding the proposed Rules replacing Onshore Orders 3, 4, and 5. And our comments really reflect E&B's strong desire to maintain the economic viability of the fields we operate.

With the current oil price environment, existing operations that are barely economic will become noneconomic as a result of implementing the new Rules. Revenue loss will occur due to premature plugging and abandonment of wells. BLM must understand the proposed Rules' potential negative economic impacts.

By giving E&B these Orders sequentially, the company has not been able to evaluate the cumulative impact of the proposed changes. These must be understood prior to commencing implementation. We have or will be submitting over 26 pages of input. Based on our analyses, we believe the proposed Rules are deeply flawed and should be reconsidered.

These public hearings are not taking place in California. The regulations are highly technical, and our operations team would like to engage in productive discussions to provide solutions to issues. E&B requests these proposals be delayed until the industry in California has been engaged.

We would like to emphasize that the replacement for Onshore Order 4 appears designed for lighter oil regimes and does not account for differences in measurements due to heavy oil and streamflood and cyclic operation.

These variances that would be required for heavy oil readings may make this more cumbersome. E&B believes the proposed oil measurement rule asking for a level of accuracy that when applied to heavy oil regimes will increase operating costs beyond necessity or value.

Additionally, BLM requires all industry to comply with API and ASTM recommended practices in one proposed Rule, and I learned today also in 5, which we have not reviewed yet. These API chapters alone in Onshore 4 cost $10,000 to review. There is no way to effective way to utilize the screen, the free screen version, and BLM has not made a good faith effort to provide these newly required standards for public review.

These must be included in the Federal Register Notice as they are part of the proposed Rule. BLM states that those in industry visit the BLM Washington or local offices to see a copy. They are not available in Washington or Bakersfield.

Please consider my comments and include them in the administrative record. We are willing to meet with BLM to discuss these issues and concerns and invite you to Kern County to engage with the industry.

We reiterate the need for time to further review the proposed changes to Orders 3, 4, and 5 and NTL4(a). Please provide us with the extension necessary to completely comment on the proposed Rules. Thank you.

MR. GREG BLOOM: Greg Bloom, and I'm with the New Mexico Oil and Gas Association.

To our out-of-state friends from BLM, thank you for coming out here and thank you for putting on the Onshore enforcement information. We appreciate your presentations today.

I was mentioning to Rich Estabrook -- we got a chance to meet about three years ago. At that point, I was the assistant commissioner for oil, gas, and minerals division in the royalty management division at the New Mexico State Land Office.

If you know New Mexico, oil and gas is a big deal. It provides approximately 35 percent of our State revenue, and the Land Office alone brings in about at this point 700, $800 million a year in oil and gas revenue yearly.

And my comments to Rich back in 2012 or 2013 it was, were related to commingling and the potential fiscal impact on New Mexico operators and State revenues from not potentially grandfathering in existing commingles, both surface and downhole.

And what we'd like to see is an explicit recognition that all existing commingles are grandfathered in. Even if just 50 percent of New Mexico's existing commingles were terminated or not grandfathered in, the State alone would see a 1 billion or 1.5 billion dollar revenue loss over the next decade, something it's pushing 20 percent, 30 percent in some fields in New Mexico.

So it's very important to the future of oil and gas employment in our State and oil and gas revenue. Also, if wells were not grandfathered in, but companies went out and had to decommingle or uncommingle a well, we would see some real surface disturbance and environmental impact from workover rigs having to go out and put new pipe down the downhole commingled wells.

So this would be a thousand miles of pipe, and you would also see pipe on the surface of the well. So we're underscoring two things here. One is potential massive loss of revenues to the State of New Mexico, and also environmental impacts from not having commingles.

Also, in the instruction memoranda, you did allow a path forward on future commingles, which are absolutely essential for the San Juan Basin and gas drilling in that area. And the application itself is quite laborious, so companies have shied away from it. It's lengthy.

And, then, finally, I would just reiterate our request that we made to BLM last week. We'd love it if you could come and do this same presentation in southeast New Mexico, perhaps Carlsbad or Hobbs. There are a lot of small companies out there that can't travel, and it would be fantastic if you could do something like this out there. Thank you.

MR. ESTABROOK: Could I respond to that quickly? To make our analysis easier or to make your comments more useful, could you estimate -- I know this would be tough -- but could you estimate the percent of existing commingle agreements that would not be in compliance with the new requirements that we're proposing for commingling?

Not right now -- just in a comment. And I would say, could you give us some input on changes to our proposed -- our commingling requirement proposal that would reduce that percentage? Does that make sense? Those kinds of comments are a lot more useful to us than just statements.

THE FACILITATOR: And those comments are due by the 14th, correct?

MR. GREG BLOOM: I'll try to get you that information. Thank you.

MR. STORMY PHILLIPS: Stormy Phillips, WPX Energy. I just have a simple question for Mike on clarification. I just wanted to understand the thought process behind separating LACTs and Coriolis measurement systems in the proposed standard.

MR. McLAREN: Yeah. We separated it. We left the LACT system as it is except for, you know, the temperature compensators and required the temperature averager, and then we put the Coriolis as a stand-alone system without going through all the LACT components, required LACT components. So it's a separate system from the LACT. That's why we proposed it that way. Does that help?

MR. STORMY PHILLIPS: Just from the Power Point presentation and some previous discussions, it seemed that one of the goals was to allow the use of a Coriolis meter as a substitute for the meter in the LACT systems, but the current language of the proposed document doesn't seem to jibe with that.

MR. McLAREN: And so hopefully you submitted that comment, but the clarification is needed in the final Rule, and it will be there.

MR. STEVE HENKE: Can you hear me okay without the microphone? I usually don't have a problem with that, as you can tell.

Steve Henke. I'm president of the New Mexico Oil and Gas Association. I represent member companies who produce 95 percent of the oil and gas in the State of New Mexico, and approximately 50 percent of that production is on Federal leases.

I want to thank Mike Nedd and his team for coming out and providing us the opportunity to comment. I have a couple of general observations. I have a couple very specific comments about Onshore Order 3 and then a couple questions.

But my comments supplement the written comments that NMOGA submitted dated October 9 and October 24 on Onshore Order 3, and we will be commenting formally on Onshore Orders 4 and 5.

So in terms of a statement in kind of a broad perspective, you know, to frame oil and gas production on the Federal mineral estate, just some statistics.

Since 2009 -- and this data is the latest available in 2014 -- Federal oil production is down 6 percent. And Federal natural gas production is down 28 percent. That's in a five-year period while simultaneously oil production on non-Federal properties is up 61 percent, and natural gas production on non-Federal properties is up 31 percent. Now, why is that?

I think there's a lot of factors, but if you're in the business of making a decision, as many of my member companies are, on whether to develop a Federal or a State or private lease, the answer is readily apparent, and it's due to the cost and regulatory uncertainty of operation on Federal leases.

And I'll just list a few things that cost member companies more on Federal than it does on State or private, and that is the application fees. In many cases, member companies are paying for the cost of NEPA compliance, including archeological surveys, threatened and endangered species surveys, sensitive areas surveys, and mitigation.

We're defending lawsuits from the environmental community in support of BLM's decisions. We're being asked to bear additional expenses to defer Government expenses in the form of cost recovery proposals that continue to crop up, particularly in the INE program.

And so if you look at those additional costs, plus the regulatory burden and the uncertainty that we're bearing, it just serves as a disincentive for investment in the Federal mineral estate and ultimately leads to a loss of jobs, a loss of -- a decrease in production from the Federal mineral estate and a decrease in royalty to the Federal Government, the States, and the Tribes.

And so I would suggest to you that this costly package of new regulations being proposed in Onshore Orders 3, 4, and 5 are further examples of requirements which will disincentivize development, decrease production and, ultimately, royalty and lead to the premature plugging and abandonment of marginal and low volume Federal wells.

And I think you're being asked to -- you're asking member companies to spend millions of dollars in modifications, retrofits, additional compliance cost for an uncertain return in terms of Federal royalty and return to the taxpayer.

And I believe there needs to be some analysis of the costs of these proposals relative to the return, as Rich mentioned, with regard to the royalty. What do you feel will be the enhanced royalty recovery from these proposals? You may have a more defensible system, but are you actually going to increase royalties?

Now, specifically with regards to Onshore Order 3 and the NMOGA comments on this, we're very concerned about the overreach proposal for Federal approval of APDs on Federal units related to private and State properties.

Data in New Mexico indicates a continuing lengthening of the approval process on APDs on Federal lands. And in face of that delay and uncertainty and cost, many member companies are drilling on private and State lands, and if we have to get in the Federal system for those APD approvals, it really eliminates our options, and we don't see the benefit for that approval in Federal units.

Secondly, the whole issue of commingling is very concerning to member companies, both surface and downhole and the uncertainty with the new requirements and what that may result in in terms of duplication of equipment, as Greg mentioned, downhole, as well as surface with, you know, additional meters, perhaps compression, additional surface disturbance, maybe additional emissions as a result of disallowing central delivery points and centralized compression.

So we suggest to you that the current instruction memorandum that was worked out in close cooperation with industry is working well, and we would like to see you grandfather in all existing commingling agreements, both surface and downhole, and allow for site-specific field office specific approval of commingling.

I think we have had engineers and professionals there that understand these reservoirs, their production, their depletion curves, and can very accurately measure contributions from different zones and different wells.

Another thing is --

THE FACILITATOR: Steve, could I ask you to wrap, please? You can come back around at the end.

MR. STEVE HENKE: I have two more statements --

THE FACILITATOR: Okay.

MR. STEVE HENKE: -- the first of which is, given the inability of BLM to meet current program demands for permitting, both in APDs and rights-of-ways [sic], and the full spectrum of existing inspection and enforcement requirements, how can you expect to implement these new Rules effectively without further cost recovery efforts from the industry?

And the final point, I think there needs to be some analysis of the benefits in either more accurate accounting or increased royalty from these proposals versus the cost to industry for equipment, modifications on the surface and downhole recordkeeping, the environmental footprint, and finally, the potential impact for the likelihood of premature plugging and abandonment of low value and marginal wells. Thank you.

MR. SEAN CASAUS: I'm Sean Casaus, C-A-S-A-U-S. I'm with Gas Analysis Service out of Farmington, and we run quite a few companies, C-6 gas samples throughout the year. And the proposed .25 percent C-6 going to C-9, we feel, is a bit extreme.

We threw some numbers real quick together this morning. C-9 analysis is anywhere from two to $300. This year alone, we've ran 5300 samples that exceed the .25 C-6 plus. 1600 samples are .25 to .5 C-6 plus with the highest dry corrected Btu reading of 1169. Overall, for the 5,000 samples, we're looking at an increase to our clients, our customers, anywhere from a million to $1.6 million just for gas sampling.

My comment today is to reevaluate that .25 and see even if we cut it to .5, that cuts out 1700 samples that our customers are having to pay for.

Another thought that we had was attaching a Btu number along with that percentage to give it more of a standard if the Btu readings are rated high enough to be affected by your C-6 pluses.

Another comment we have is if you could elaborate on sealing gas samples. Right now, the way we seal a gas sample is, we pull a vacuum on it. We put a vacuum on it. We put a tag with a little bag on it that has a sample zone number on it. The tag is not filled out, and there's caps put on each end wrenched tight. That's the only way we know of to effectively seal a gas sample bottle. So those are my comments.

MR. ESTABROOK: Thank you. Great comments, very helpful. The data that you cited, will you submit that, too?

MR. SEAN CASAUS: Yes, sir.

MR. ESTABROOK: Great. That would be really helping. The sealing -- that's another bullet I forgot -- the sealing to gas owners. API and GPA go into great detail of cleanliness and steam cleaning procedure and all that that you're very familiar with.

It seems like a really important thing, and my only thought there -- again, we are throwing this out for feedback just like what you have given, which I appreciate, is the importance of having a clean cylinder out there to do a clean sample, how would our inspectors know it's not been contaminated or opened, and what you described sounds like it might get to what we're trying to achieve.

So, again, it's possible that what you have -- what you are going to provide could be an alternate solution that would do what we were trying to do in a different way.

But the reason we threw the question out is, I have no idea how to seal a gas cylinder. That's why we're asking the question. Okay? So thank you.

THE FACILITATOR: Frank Santiago?

MR. SANTIAGO: I'm going to pass.

THE FACILITATOR: You're going to pass? Really.

Okay.

THE FACILITATOR: Okay. Christi Zeller.

MS. CHRISTI ZELLER: My name is Christi Zeller, Z-E-L-L-E-R, I'm with the La Plata Energy Council here in Durango. And I want to welcome you to Durango. We don't usually have people from Washington, DC come and want to listen to what we have to say, so thank you.

I want to reiterate the comments I've heard. I support all of them, and I just wanted to add a few more things, if possible.

You know, my member companies do not think that we've actually done the right amount of outreach yet for the regulated communities.

Particularly, I'm a data person, and so I go on the website to see who's producing the most natural gas, for instance, by State, Texas, Pennsylvania, Oklahoma, Wyoming, Wyoming, Louisiana, Colorado, and New Mexico. Those are your top seven for natural gas.

If I take your producible Federal wells, fiscal year 2014, No. 11 is Wyoming. You need a meeting in Wyoming. No. 2 is New Mexico, as stated. You need a meeting in New Mexico. No. 3 is Utah. You need something in Utah.

We heard today from California, the No. 4. No. 5 is Colorado, and No. 6 is Montana. And I know you're going to North Dakota, but they're No. 9. So one of my hopes is that you can actually get to the data you're looking for. Your presentation had several examples of what you need from industry and industry needs to know in what format, how we can get that to you, but we really need to have a set of across-the-table kinds of conversations in the states I just listed for you.

Additionally, apparently according to the hydraulic fracturing rule, there's like 63,000 onshore gas wells, and 5 percent of it's oil. There's no way for us to even figure out how many natural gas are those 63,000 and how many are oil, which really makes a difference in terms of commenting and economics on 3, 4, and 5.

We're looking forward to -- actually, I had a conversation with your meeting people this morning, and one of the enforcement handbooks very concerning to us is that we know you're going to have one, but will we be able to actually make comments on it so that we understand it in the same terminologies and are something that we can put into the business practices of these operators and transporters?

One of the biggest concerns we have here in the San Juan Basin is this BLM requirement for dry Btu. That's a very big concern here. Gas metering and the drivers is the wet. Most of our internal contracts are based on wet, so that's going to be a very expensive change for us.

Just to let you know, more than two-thirds of the

La Plata County wells are coalbed methane here, and about 1/3 are conventional. We really have no oil, so some of the other thresholds on oil like 50,000 barrels for reporting -- in Colorado, La Plata County, we have 30,000 of barrels of oil alone, so that would make us look at this, I think, every quarter. So that's a little concerning, as well.

The volumes are very frightening. I pulled up two Indian wells when you were talking about what a marginal volume, high volume, low volume is. These are older wells that are declining in production by about 7 percent here in La Plata County. One month, we had 620 mcf. Another month was 1292 mcf. And the Btu's were ranging from 1065 to 1080, so we're very concerned about the retroactivity of this, particularly, in case you did not know, the price of natural gas in the San Juan Basin in November was 2 dollars an mcf.

So I think it's woefully incomplete to look at your economic data based on projections based on I think it was 5 dollars an mcf. That's just not what we're seeing. So I don't know if there is a way to truth [sic] out the future price of natural gas, but that's a big concern here especially with the retroactive.

And finally, I did a control F, my favorite feature of any sort of document I'm looking at, and your Onshore Order No. 3 has the word "constant" in it 62 times. You're interested in additional information about the cost of compliance relative to royalty lost. The BLM is interested in any additional information about costs of compliance relative to royalty lost from maintaining the existing exemptions. The BLM is asking for data on the cost of this retrofit and the number of meters that it may affect. It just goes on and on.

And we want to be helpful, but in a comment letter due on the 14th, there is not enough time to gather what we need for you, much less to be able to determine what this is going to cost.

And I want to also say Steve Henke is very right. We're looking at premature plugging and abandonment here. The Tribe's Indian minerals or are our No. 1 BLM issue, but there are some BLM wells here, as well, but it will be cheaper to go on fee than it will be to do and to develop Federal minerals, especially with retroactive and our declining price, as well as product. So thank you.

Oh, can I add one more? I don't know if you have been on the Colorado Oil & Gas Conservation Commission's website, but there are two Rules, Rules 328 and 329. One is for gas measurement. One is for oil measurement, as well as looking at data for Btu's, and maybe you can use that and extrapolate, since we were No. 5 in the nation for Federal production here. So thank you.

THE FACILITATOR: Now, that concludes the list of people who signed up to speak. Now we'd like to hear from people who didn't sign up. Would you state your name, please, and where you're from?

MS. RUENELL SEALE: My name is Ruenell Seale. I am here today representing myself as a member of the State or as a citizen, a concerned citizen, of the State of New Mexico and as an employee in the oil and gas business. I work for a transporter.

I am terrifically concerned about premature plugging and abandonment of reserves that we will never get back if these things are enacted as they are written.

From a transporter's standpoint, there are very old systems in place in San Juan and will cause a significant impact on all transporters in New Mexico in the San Juan Basin -- significant cost. And when I say significant, I'm talking about tremendous cost.

One company alone has over 9,000 meters that will require tremendous additional testing that is going to cost considerable man-hours, which will then be passed on to producers who will then look at their bottom line and plug and abandon those wells.

We will never get that back. That will be lost revenue to the Federal Government, to Indian Tribes, and to the State of New Mexico. I believe that you should look at grandfathering and, also, look at what you're going to achieve in percentage of increase from all of these regulations as compared to plugging and abandonment of at least a third of the wells in the San Juan Basin in New Mexico.

I would like to also speak to the proposed Facility Measurement Point. This will require most software, if not all software, to be completely rewritten. The timelines for that are tremendous. The cost of that is tremendous and, again, factors into the cost that will be passed on to producers.

The number of failed pieces of equipment for what we look at as a very small, minor increase in accuracy will be tremendous, and that equipment will be -- will need to be replaced. That equipment is not available.

The timelines for replacing that would require those wells to be shut in for long periods, which will cost reserves and efficiency in those wells over the long term.

I would also like to speak to the point of not allowing drip pots to be used in any part of the gauge lines in the San Juan Basin. Approximately 90 percent of the meters have drip pots, meaning that most gauge lines will have to be retubed. This is a huge effort, a huge expense, and a huge timeline that's going to cost production, as well as money, for the physical work.

Also, the flow rate and volume calculations not being allowed, performing the current AGA measurements will have to be changed, and only as you stated, the API, 14.3 API, 14.2 will be allowed.

The current meters and current CMS measurement system use the AGA calculations, and changes would be required for meters and measurement systems. Again, another huge concern and a huge timeline. Thank you.

MR. ESTABROOK: Could I ask one question? You said 90 percent of the gas meters have drip pots?

MS. SEALE: Yes.

MR. ESTABROOK: Do you know why?

MS. SEALE: Because the way the system is designed and the contracts are written, the condensate belongs to the transporter.

MR. ESTABROOK: Are these the drip pots going from the orifice plate up to the transducer, or are these like constant collection pots on the pipeline?

MS. SEAL: On the pipeline.

MR. ESTABROOK: Okay. Thank you.

MR. TOM MULLINS: My name is Tom Mullins, M-U-L-L-I-N-S, with Synergy Operating, spelled S-Y-N-E-R-G-Y Operating. We operate on Federal lands in the States of Wyoming, Utah, and in New Mexico, and I'm based in Farmington.

Specifically, throughout all of these Rules and regulations, targeting the Royalty Simplification and Fairness Act, in particular, which is targeted towards marginal producing wells, I don't believe any of the regulations are in compliance with that.

I think there's an attempt to recognize that fact with the low volume designation and split-out in production, but I don't think it meets the actual Congressional intent, which also has audit relief and royalty relief and variances.

In the San Juan Basin, in particular, approximately 60 percent of the producing wells currently would qualify under the Federal definition of marginal wells. I think we need to take a look at that, take a step back on all of the regulations.

I agree with the comments on commingling. It's a significant issue in the San Juan Basin. We also have some wells over in Utah, and I just got a letter a couple days ago saying the metering installations that have been in place since 1981 are no longer valid, and the BLM office is asking me to change the way I'm installing the meters and, obviously, this gets into the royalty calculations and the revenue.

So, you know, the impacts related to that commingling and how things are measured is a big issue.

Utilizing best management practices, which appears to be the direction of updating some of the regulations to bring forth some of the best management practices that are currently used in industry and then applying those without grandfathering or retroactively on some of the meters, specifically looking at some of the item like meters tube.

I mean, if you have got a 4-inch meter tube and 1/4 inch orifice plate because the volumes are down so far, and I know there are some exemptions, I just think we're choosing -- we are doing a lot of work and chasing a lot of things without calculating actually the economic impact, you know, that relates to this.

The measurement -- the FMPs are a concern that come back on the reporting and how is there going to be any retroactive nature of that going backwards in time? That's a concern.

Those are the comments that I have right now. We'll send in other written comments. Thank you.

MR. TRIPP PARKS: Tripp, T-R-I-P-P, Parks with the Western Energy Alliance in Denver. Thank you all for coming to Colorado. I appreciate the opportunity to speak.

We submitted substantial written comments on Onshore 3, and we are trying to work with API to develop some very extensive written comments for you all on 3 and 4. So today, I plan to just keep it pretty broad.

I would just like to echo the comments earlier about the timing of the Rules. It was mentioned that 3 and 4 granted an extension, and Onshore 5, which is the longest and most detailed of the Rules, was given no extension. We were only given 60 days, and there was only a three-week comment period.

These are very interrelated Rules, and there's a lot back and forth between them, especially with 3, and I think that the timing is just not sufficient for these Rules.

And along the lines of the interrelated nature of them, I think the cost analysis that goes into looking at these three Rules together is just insufficient. I think there will be substantial cost as has been covered to operators for compliance to these Rules.

And, finally, something I think we haven't touched on much today is the impact to BLM on these Rules. These are very substantial Rules that are going to dramatically increase the workload for BLM and, you know, we've heard and we all know that there are already substantial delays for leasing for APDs at BLM, and I think the comments earlier was for FMPs that have a nine-month period for compliance.

BLM said, "Well, if it takes 36 months, that's fine. You will be okay."

I think that is pretty reflective of the kind of response times we see from BLM. I think that's a big concern in adding to the workload with these Rules.

And maybe to open it up to you all with the question, have you all considered jointly the expected increase in workload on BLM's staff and the ability to respond to some of the timelines in these Rules within the designated periods?

MR. NEDD: Thank you for the question. Certainly that's part of our consideration in implementing any Rule. BLM is looking into the resources it is going to take. Let's be clear in the FMP.

I think the comment was in the context of if you submit your application in a timely manner, there would be no cease in operation while BLM worked through that application.

But, as you know, BLM will continue to prioritize and make sure we're paying attention to the workload that needs to be done. But thank you for your comment, and it is part of the consideration, and I appreciate that.

MR. JOHN ALEXANDER: Okay. Thank you very much. I'm John Alexander. I'm employed by Dugan, D-U-G-A-N, Production Corporation in Farmington, New Mexico. We operate 982 wells, the bulk of which are on Federal leases.

I've probably operated more off-lease measurement, commingling wells than probably a lot of people. They're absolutely critical. I could not produce Federal minerals, State minerals, or any other minerals were we not allowed to commingle those.

These gatherings systems have been in place for decades. To go back and to have an authorized officer on the Bureau of Land Management tell me I'm making too much money -- is 10 percent an appropriate amount to make? I'm sorry. That is just overage. That is just overage to determine if 10 percent is too much money for me to make on an oil and gas operation. I can't go back and rearrange -- I could, but at a huge cost to me.

I know that's not your intent. Guys, we lease Federal acreage. You manage Federal acreage. I respect that. This should not be an adversarial relationship and, unfortunately, many times it seems that way. We'd do anything we can to make this efficient. We'd do anything we can to produce as much oil and gas for the people of the United States as we can. That is my goal.

I have never woken up in the morning and -- forgive me. I have never woken up in the morning and think, how can I do something wrong? And you haven't, either. That's what I do. If I can't operate my gathering systems, a lot of wells are going -- you heard that from a lot of other people. That's right.

Specific oil and gas Onshore 4, a lot of good stuff in there. Some of it works. Onshore 5, you need to take a close look at the information that you want displayed on your (inaudible). Some of them cannot do that. If you need to do that, fine, but to display all the things you need to display. I understand you may need to know it, but your technicians need to take a look at, can we do that with the meters that are used?

Let me close by staying that first, thank you for coming and listening to us. Understand, I live this every day. I've been in this business for 46 years -- probably more than most people around here. There's a lot of experience here. Okay.

A very wise man once told me experience is a good teacher, but it's a hard one because it gives the examination first and the lesson later. I've failed a hell of a lot of exams, and I learned the process.

And so work with us on this -- a lot of room. It's moving way too fast. All of us are going to have difficulty with this. Thank you for your time.

THE FACILITATOR: Okay. C'mon. Wake up.

MS. KARIN FOSTER: Good afternoon. My name is Karin Foster. That's K-A-R-I-N. Foster is the last name. I'm an attorney and executive director for -- of the Independent Petroleum Association of New Mexico. I'm a New Yorker, so I talk fast.

I'm an attorney for the Independent Petroleum Association of New Mexico, the majority of the companies who employ 38,000 people in the State of New Mexico. We are -- the majority of the companies or, at least the members of the board that are on the Independent Petroleum Association are small producers. We're the family-run producers, family-run companies who generally employ less than 25 people, but we're the backbone of the operations in the State of New Mexico.

We operate marginal wells, as Mr. Alexander mentioned. Many of our operators have marginal wells. And the 10 percent rate of return that you have in Onshore Order No. 3 is extremely unreasonable.

What you're telling operators is that for something to be defined as a low volume well, it has to have less than a 10 percent rate of return. That doesn't really make any sense.

I would also ask that your marginal -- that your definitions match with those that are required by the IRS for marginal wells, and I don't believe that they do.

I'm also really concerned about the amount of time that it's going to take the BLM to give us all these approvals. First of all, your national production management team that's going to give us the approvals on all the meters, how long is that going to take in order to get those approvals done and all your testing done on those meters?

How long are we as industry going to have to wait until those meters are approved and put on your website to know if we have the right meter, or we have to run out and go get other meters that are now approved?

I think there's going to be a lot confusion, especially with small operators that might only have, you know, 100 wells or so or even less, to know that they have to look at that website and determine if their meters are the right ones to have and have to go out and get new ones.

I'm also concerned about the length of time -- and a lot of people went over this -- on the FMP approvals. In the comments that the Independent Petroleum Association of New Mexico submitted, we estimated that it was going to at least have to hire 148 new people in the State of New Mexico, BLM employees, just to process FMPs within a three-year time period. That's a lot of additional people.

We're also as an industry facing EPA regulations for air quality, and as marginal producers, a lot of time, we have to vent and flare because our pipelines aren't getting out to our locations. Why are pipelines not getting there? It's because the BLM is not giving us the right to waste, and we go and we talk to BLM and they tell us that they don't have enough employees to give us right-of-way approvals. And now you're requiring -- you're going to require new FMP approvals, we well.

As marginal producers, we're obviously concerned with the cost of new equipment that we're going to have to put on there. I asked during the break a question of you, Mike, and Rich, about the gas chromatographs and whether margin wells and low volume wells were going to have to put those gas chromatographs on.

I looked through the copy of the Rule that I have, and it's not clear whether small producers are going to have to get gas chromatographs for those low producing wells. So I ask for that clarification.

The cost of additional testing is going to be exorbitant, especially for those miniscule drops in percentages for your mistakes that you claim that are out there.

Also, on your presentation, you note that our recordkeeping is going to require of not only the operators, but also transporters, and that recordkeeping is going to be required through the measurement royalty point or the point of first sale.

So now we have the Facility Measurement Point, the FMP and we also now have to worry about the royalty measurement point, and we have to worry about the point of sale for all this for recordkeeping, and then we also still have to deal with ONRR requirements with their marketability points and payment on royalty to them.

You're making things much, much, much more confusing than they need to be. I would suggest, like this young lady mentioned before, you need to go sit down and talk to ONRR and look at what their requirements are and match them with your requirements instead of us having to do all this recordkeeping for all these different random points along the time. It doesn't make any sense.

You mentioned, Mr. Estabrook, that one of the things that you acknowledge and the reason that you're going to require transporters to have recordkeeping is that independent producers by definition don't own the gathering lines, and so you're going to require them to do recordkeeping.

Well, we don't own measure tubes, either, the metering systems. Those are owned by third parties, as well. So it would seem that from your presentation that the onus on the time chart that you had for testing the meter tubes is again on the operator, but we don't own those, so it doesn't make any sense. The independent operators do.

Finally, I'm going to close on the point that Mr. Henke brought up, and I think it was a very good one is that -- Mr. Alexander brought it up, as well. The issue of commingling. The San Juan Basin has been around for a long, long time.

We have operators that have been there a long time, and many, many of our wells were commingling. We need to have those grandfathered. It really only makes sense. If you uncommingle those and you require us to separate them out, think about the surface disturbance that we're going to have in the San Juan Basin.

One of the things that the BLM has required us to do over the years is to cut our well pads back to the anchors to really have as little surface disturbance as possible, to have horizontal wells, to use multiple wells on a pad. And here you are talking about a proposal to uncommingle wells that potentially have very, very drastic surface impacts, which I'm sure even the environmental community which is not here in the room today would not want to hear.

Finally, I'm an attorney. Mr. Estabrook, you're not. You stated that. Liquidated damages that would be required with an immediate assessment basically means that operators would need to compensate the BLM for employee time to go out to a location. That doesn't make sense.

Our APD rates have gone up in the ten years that I've been representing industry from -- when I started, I think it was $3,000. Now it's $9500, and who knows when it's going to go up. If your assessments and your penalties are going to be tied into having to pay for BLM's time to come out to our location, that is just patently unfair.

Thank you for the opportunity to comment. Thank you for coming out and speaking to us. And I would also suggest you come down to southeast New Mexico and talk to our operators down there. Thank you.

MR. ESTABROOK: Let me address two of your comments. I'll take the easy one. The online gas chromatographs would never be required on a marginal or low volume FMP, and it's pretty clear, but maybe not as clear as it should be, and the only reason we would only require an online gas chromatograph is if spot sampling couldn't be done frequently enough to obtain our uncertainty requirement for plus or minus 1 percent. But marginal and low volume wells meters, I should say, are not subject to the uncertainty requirement at all for anybody so, therefore, it would simply not apply.

It's a little bit roundabout, but it is clear. It's just a little -- it takes a little to get there.

MS. KARIN FOSTER: Okay. Thank you for that clarification.

MR. ESTABROOK: Let me talk about the 10 percent rate of return and commingling. I think maybe there's a little confusion on that. If you don't mind, I'll take a couple minutes. This addresses the previous speakers, too.

MS. KARIN FOSTER: Please go ahead. Thank you.

MR. ESTABROOK: I think it might address your concerns. So commingling -- actually, the presentations I give on commingling, I always say commingling is a great thing. There's lot of advantages to it.

It's not the commingling. It's the allocation is the problem because allocation necessarily with a few exceptions reduces the accuracy of the measurement and our ability to verify that measurement.

So to approve commingling, we have to be able --

well, let me say -- let me first go over -- and Mike went over this.

There's three situations where we would approve commingling. One is if there's no royalty impact to allocation. So for example, you have two Federal leases. Royalty distribution, royalty goes to the same place. You can commingle them. That's acceptable commingling because I don't care what the allocation is -- 90/10, 80/20, 50/50. We're going to get the same royalty regardless. So that's readily approvable, and that's proposed in the Order.

If that's not the case, where you have different ownerships or different royalty rates or something, then the BLM has to defend a position saying that, "We are willing to give up or waive Onshore 4 and 5 uncertainty and verifiability requirements. If you commingle different properties, we are giving that up."

Uncertainty is going to go way up, and our ability to independently verify those volumes is going to be lost for the most part. So in order to say that we're going to now waive 4 and 5 requirements for lease measurement on Tribal and Federal, we need a pretty good reason.

And so we've come up with two pretty good reasons that are in the proposed Rule. One of the reasons would be for extenuating circumstances such as environmental conditions that you mentioned. And there was clearly, the only way to independently measure, it's going to cost footprints and new tanks -- that's the stuff we've got to address. So that would be one of the recognized extenuating circumstances.

Another one would be maximum ultimate recovery. This applies to where you have to commingle two formations because one formation doesn't have the reservoir energy anymore to lift the fluids. So you downhole commingle with another formation that has energy in it, and you can produce both formations, and you can achieve maximum ultimate recovery.

The third reason is specifically for low volume. Now, if an operator -- if the costs to an operator to independently measure, to unmingle or not commingle was so great that they would choose or opt to shut in that lease or that meter, then we don't want that to happen, by the way. We don't want people to shut in. We don't want people to plug and abandon.

That's the opposite -- our goal is revenue. So it would be silly for us to get a bunch of plug and abandons. So the low volume category in the proposed Onshore Order 3 is to address that situation, and we are looking for comments on that.

The rate of return is really specific. What we decided was, we need an objective test to figure out what low volume means. We can't just have operators coming in and say, "I'm going to shut this well in if you make me do this."

I mean, they can come in and say that, but we need some kind of objective test. And so that was the whole idea of our economic test for the commingling situation -- some kind of an objective test that we could back up with data and we could defend the decision to sacrifice Onshore Orders 4 and 5 requirements.

So I gave an example this morning. I'll do the same one. Davis was here this morning. So let's say you have two leases, a Federal lease and a private lease, let's say. And right now, there's one tank. And the oil flows into both, so the two leases are commingling and measured at one tank.

Now we say you have to unmingle that, which would require another tank, let's say, on the Federal lease. So an operator, I think -- I'm not an operator. And that's one of the reasons we ask for comments because we don't have the experience you guys do.

An operator, I would think, is going to say, "Okay. So I've got to buy this $50,000 tank in order to comply with my regulations." And they're going to run some kind of economics test in there and say, "Based on my low production, if I invest" -- I use that term loosely -- "invest $50,000 in a big tank, I'll never make that money back based on my production going out 10 or 20 years. And so, therefore, as a prudent operator, I've got no choice but to shut that in."

Okay. Now, that's the exact situation we don't want to have. So if that's, in fact, the case, then you get your commingling. You get to commingle because we don't want you to shut in, but we need some kind of objective test to make that economic case.

So what we're proposing is that it's a rate of return test just on that $50,000 tank. So if you invest in that $50,000 tank, due to continued production if we let you continue production and you go out 10 or 20 years the life of that tank, could you make your money back on that tank and 10 percent rate of return on that tank, on that specific investment to unmingle or independently measure?

It's an economic test. Now, I don't know if 10 percent is the right number. That's why we're asking, and we don't really care about your economics. We're trying to simulate a prudent operator's decision. I guess I'll put it that way.

Maybe most companies would look at a 10 percent rate of return and say, "That's ridiculous. That's way too low for our company."

And, you know, through this whole process, companies have been very reluctant to supply us with their internal rate of returns. So we had to guess, and 10 percent was our initial guess. Now, if that's way too low, tell us and, you know, we will consider a different number.

But, again, we're not trying to get into your economics. It's a economic -- it's a simulation of that specific tank that you have to buy in order to independently measure. That's what that is. I don't know if that helped or not, but that's the intent of that. Okay?

MS. KARIN FOSTER: Okay. Thank you very much for that explanation.

MR. WADE: I would add one other item on that commingling for downhole in particular. Where that downhole commingling is basically for the same case, the same lease, and that commingling would have no impact on the royalty, so you got a well on Lease No. ABC that has multiple formations.

Each of the formations is paying 12-1/2 half percent, and you want to commingle downhole. That is not commingling for the purposes of royalty determination. That is a separate set, and this is not -- would not impact those situations.

Not all downhole commingling would require reauthorization -- only those instances where the commingling impacts royalty. Okay? Does that help clarify a little bit, maybe, on some of the downhole commingling? I was hoping it would help. I thought I would try, anyway.

MS. KARIN FOSTER: Gentlemen, thank you for your comments, and the Independent Petroleum Association of New Mexico will be submitting comments on Onshore 4 and 5.

We've already submitted to No. 3.

One suggestion that I would make, Mr. Wade, is on the website for people that have questions relating to these meetings we have, your phone number is on that website, and you're obviously here in Colorado and not DC, so you may want to make a human being available in the Washington office in case the people have questions on one of these meetings, since you do have two more meetings coming up. So thank you for being here today.

THE FACILITATOR: Would anybody else like to speak, comments?

MR. RORY McMINN: I'm Rory, R-O-R-Y, McMinn, M-c-M-I-N-N, Read & Stevens out of Roswell, New Mexico. I just have a question. Tell me what the implementation date is. You have December 14th to get comments in, but what kind of time frame do we have to prepare for?

MR. NEDD: So December 14th comments comes in and the rest of comments, we would enter into comment analysis to move towards a final Rule, and that varies. You know, it varies. Once we receive comments, then we would move forward. Would it be two months, three months? It's hard for me to say.

I understand we will look at the comments and one thing is, we will be very thoughtful of these comments and be very mindful of what you submitted. I don't have a time frame.

MR. RORY McMINN: Thank you for your response. My next question which you just triggered then would be, once you make the decision to go forward with the changes, with the comments having been taken into account, then how much time are you going to allow the operators to effect the changes that are going to be required before the full implementation is going to be put into place, and the folks with the enforcement book in their back pocket that come to a location are starting to pull out their ticket book?

MR. NEDD: So implementation traditionally is, when a Rule is published, 60 days after it's published, it goes into effect. However, experience and history will show, BLM allows various implementations, depending on the complexity of the rule. Again, I don't have that solved.

We're going to look at the comments. We are going in. These are together very complex Rules, and we will look at that implementation time, but historically, by law, it's 60 days or no sooner than 60 days that the Rule is published. But on hydraulic fractures, it was a longer period of implementation.

MR. ESTABROOK: So there's two kinds of implementation periods that we need to be aware of. One is the one that Mike was talking about, 60 days -- whatever it happens to be before any of the provisions of the Rule become effective.

Built into 3, 4, and 5 are grace periods that would start after the implementation period is gone. Okay? So for Order 5, for example, the grace periods depend on the category. So for high volume, there's six months' grace period, or very high volume, it's six months. Very high volume is one year. Low volume, it's two years, and for marginal volume FMPs, it's three years.

For a very high volume FMP, you would have whatever the implementation period is, 60 or 90 days, plus that six-month grace period, so there's actually two things.

And Order 4 is 180 days -- is that right -- for most things? So 180-day grace period for Order 4 on top of that implementation period. And for Order 3, Mike has some grace periods for the FMP part of it, anyway.

THE FACILITATOR: Okay. Anybody else? You are the experts in the room, so leave all the information you have.

MR. CHUCK CREEKMORE: Chuck Creekmore, C-R-E-E-K-M-O-R-E. I have a concern on your commingling definition of no impact.

And in the San Juan Basin, the Basin is covered with Federal exploratory units where the royalty owners have entered into a contractual agreement modifying the royalty provisions under their leases.

And we sometimes have four or five or maybe six producing reservoirs, and to economically develop these units, we have to commingle our wells.

Some of the leases will be in a participating area and some of them won't, so the different reservoirs will have different interests, but we feel like there should be an exception to the commingling no impact because they have entered into these units agreements, the royalty owners have, both the fee, State, and BLM.

MR. ESTABROOK: Great question. And that's an important point to raise. If you have a participating area with 100 wells in it on dozens of different leases, that's not commingling to us.

Commingling would only be if you're combining one participating area with something else, like another lease or private land.

MR. CHUCK CREEKMORE: No. What I'm talking about is a participating area in one formation being commingling with a participating area in a lower formation or a higher formation.

MR. ESTABROOK: So that would be a downhole commingling situation?

MR. CHUCK CREEKMORE: Downhole commingling within the unit area.

MR. ESTABROOK: So under the proposed Rule, it would still have to fall into one of those three areas. But

PAs typically involve a lot of landowners.

MR. CHUCK CREEKMORE: Yes, they do, but they won't have the same undivided interest in each of the formations, so they would be exempt?

MR. ESTABROOK: No.

MR. CHUCK CREEKMORE: They would not be exempt?

MR. ESTABROOK: No, because the allocation -- let's take your one PA that has some landowners' split to it. Let's just say it's 90 percent Federal and 10 percent non-Federal. Then you're going to commingle with that lower PA, 50 percent Federal and 50 percent non-Federal. Does that seem like a reasonable example?

MR. CHUCK CREEKMORE: Could be.

MR. ESTABROOK: The question on that first category, the question you have to ask yourself is, is the allocation method going to impact royalties? And because the landowner split is different between those two PAs, if you downhole commingle that. It matters how you allocate that because there's direct royalty impacts.

The more you allocate to the top PA, the more the Federal Government is going to get. So the allocation matters. So that first category is gone because there are royalty impacts.

Then you drop to the low volume one, the 10 percent rate of return on the equipment necessary to achieve independent measurement. PAs typically are larger, typically deal with higher volume, so you probably wouldn't qualify for that, but you might. But let's say you wouldn't. Now you drop to the third threshhold, and that's extenuating circumstances.

Now, on that one, there's two extenuating circumstances that I think are relatively common. One is for environmental reasons, and one will be for maximum ultimate recovery.

Now, in your downhole commingling case, perhaps the reason you're doing that is because you need the reservoir energy from that lower formation to lift the fluids in the upper formation. So by commingling, you would be achieving maximum ultimate recovery, which is one of the criteria that we can approve commingling for. So you would still require a commingling approval, but under that scenario, we would probably grant it based upon what the local field office determines under the premise that maximum ultimate economic recovery of those formations is more important than strict adherence to Onshore Order 4 and 5 measurement standards. Okay. Does that help?

MR. CHUCK CREEKMORE: Yes.

MR. STEVE HENKE: Steve Henke with New Mexico Oil and Gas Association. I see some inconsistency with the comments you're making. If you signed agreements and now you're going to retroactively modify those agreements, isn't there some liability there that may be more costly than any royalty enhancement?

MR. ESTABROOK: I don't think that's the case. I mean, there's two participating areas. The combining of those is commingling under the current definition of commingling.

It would still be commingling, and what we're saying is, by commingling those PAs with the allocation method has direct impacts on who gets how much money. We better have really good reason, documented reason, of why we're going to abandon Onshore Order 4 and 5 measurement standards in order to allow that to happen. So I guess I don't see your point.

Okay. Clarify for me, please.

MR. TOM MULLINS: The short version is -- this is Tom Mullins. The State of New Mexico has already approved the commingle allocation formula, and it's already in existence. It may have been in existence for a number of years, but what you're basically saying is that you're going to come back and take a look at it in all of these particular instances and decide whether it's good or not.

MR. ESTABROOK: I think that's correct. I think that's what we're proposing, yes.

MR. TOM MULLINS: And that's what the concern is.

MR. ESTABROOK: Okay.

MS. JENNIFER BRADFUTE: Jennifer Bradfute. I'm an attorney with Modrall-Spurling in Albuquerque, New Mexico. When there's a communitization agreement in place that has been approved by the BLM that commingling has occurred under, are you saying that commingling will no longer be allowed if it's not found to be -- have a net no-royalty impact?

MR. ESTABROOK: Okay. I'll try to be clear because I think it gets confusing real fast.

MS. JENNIFER BRADFUTE: Yes.

MR. ESTABROOK: So a CA, let's say, could have multiple ownerships.

MS. JENNIFER BRADFUTE: Yes. And let's say one lease has a sliding scale royalty within the CA, and some of the other leases have the standard 12.5 percent.

MR. ESTABROOK: Okay. So you drill a well on that CA. There's no commingling unless you combine that CA with another lease or another property outside of that CA.

MS. JENNIFER BRADFUTE: But under the existing operations that have been ongoing under the CA, there has been commingling in the past.

MR. ESTABROOK: Between that CA and another property?

MS. JENNIFER BRADFUTE: Not another CA, just two leases within the communitization agreement.

MR. ESTABROOK: From our standpoint -- this is where it gets really confusing. From our standpoint, that CA is one property.

MS. JENNIFER BRADFUTE: Okay.

MR. ESTABROOK: And so there's no commingling.

MS. JENNIFER BRADFUTE: Okay. So that wouldn't be commingling?

MR. ESTABROOK: Right.

MS. JENNIFER BRADFUTE: And the same would be for different leases within an existing unit -- different leases within a unit agreement?

MR. ESTABROOK: In a PA. You have to distinguish a unit agreement from a PA -- different leases developed within a PA. You can combine -- there's 100 wells in this PA and all kinds of ownership within that PA. You can combine the production from all those 100 wells, measure it once, and that is not commingling. It requires no approval from us.

MS. JENNIFER BRADFUTE: Okay. And when you're combining two different PAs that have already been approved by the BLM, the BLM is now going to go back and look at those arrangements and could rescind those?

MR. ESTABROOK: Yes.

MS. JENNIFER BRADFUTE: In doing so, is it going to give notice to the different interest owners within the leases because it might be impacting the different royalty payments to overriding royalty interest owners and working interest owners who may not be interested in this commentary period?

MR. ESTABROOK: Order 3 has provisions for rescinding and all kinds of stuff.

MR. WADE: Before we rescind anything like that, we have to notify the operators and all the other operators associated with it that we are looking at it and that we are wanting to do that, and everybody associated with that would still have full appeal procedures, appeal rights as if that -- they have now. There would be no impact there at all.

So, yes, all the operators that would be associated with that commingling issue would have to be notified. They would be given an opportunity to come in and work with us, try to resolve the issues. That's our first preference. Let's try to fix it before we do any rescinding.

I believe that's specifically mentioned in the draft Rules of that. We want to work with the operators first to try to bring the situation into compliance or to get information so that we can approve through 1 of the 3 exceptions.

We wouldn't just -- oh, this one doesn't meet it and rescind it. We would work with everybody first off as is contained in the current draft.

MS. JENNIFER BRADFUTE: Is that changing the obligations under the agreements for the participating areas? So is there an agreement basically in place to commingle that the BLM has already approved? And what I'm really asking is, is there a contracts clause issue here?

MR. ESTABROOK: I'm not aware of any. If there are some, we need to hear that, obviously, but I don't think the unit agreement language has those provisions in it. I could be wrong, but --

MS. JENNIFER BRADFUTE: But that might be something that --

MR. ESTABROOK: It might be something. If that is the case, then we should know about it.

MS. JENNIFER BRADFUTE: Thank you.

THE FACILITATOR: Okay. Anybody else?

MS. HEATHER RILEY: Heather Riley. So on the exception for the downhole commingle, would you allow operational exceptions, or does it have to be the economic one?

So in other words, if we have issues downhole and so there a reason we commingled it or took out our packer, is that -- would that be considered an exception?

MR. ESTABROOK: Yeah. The reason you took out the packer, I'm guessing, again would be to use the reservoir energy of one formation, and that's a very common example I've heard.

So if you didn't do that, you couldn't basically produce that upper formation because it's going to load up.

So the rationale there is maximum ultimate economic recovery, and that would be our justification for granting that commingling approval. And that's one of the things that I believe is specifically discussed in the proposed Rule.

THE FACILITATOR: Anybody else? No? We have ten minutes. Thank you all for coming. And I'd like to hand the mike over to Mike Nedd to say goodbye.

MR. NEDD: Again, let me thank you all for venturing here with us. I know some of you came from far off. There's been lots of discussion about having meetings in other locations. We receive a number of that.

We have over 33 offices operating throughout the United States, and we know it's been very difficult to get to every office location. I believe in the next day or so, we will be adding a call-in for those places like Hobbs and some other places where you can call in and be able to do some of this. So we're trying to accommodate to the extent we can.

Let me just say, a number of you recognize these Rules were put in place in 1989. They're very old Rules. They're 26 years old, and so we have to update these Rules. And the question becomes, how do we do it? And your input, your comments, we certainly want to take into consideration to make certain we put Rules in place that make sense and work for all, so that's our goal. But we all recognize and understand we have to update our Rules. It just doesn't allow us to move forward.

The second thing is, you know, it's a very complex issue, and so we heard a lot of your variations and your comments today, and I want to encourage you, encourage you, encourage you to submit those comments. We have captured it. But if you have more data for supporting the things you have been saying, as much as you can, submit that. That would be helpful.

The anecdotes that we have, that sometimes doesn't help. We need the specifics. So the comments, again, we need the specifics. Again, we would appreciate that, and the team that is here, and we have been doing Rules -- at least, I have been involved with the Rules. We do really take all your comments into account. So we want to thank you for that.

Again, we are going to be in Oklahoma two days from now, and then next Tuesday we will be meeting in North Dakota. We certainly appreciate all of you. We invited a number of people just beyond the operators, and so, you know, many individuals in the room, whether you're operators, public, Congressional, or whatever it may be, we invite all of you.

Again, our comment period will close December 14th unless something changes, so if you could get the comments in by then, we appreciate that. I want to thank the BLM Colorado and all our subject experts, and I appreciate you being here.

(Proceedings concluded at 3:57 p.m.)

REPORTER'S CERTIFICATE

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